BEFORE

THE PUBLIC SERVICE COMMISSION

OF SOUTH CAROLINA

DOCKET NO. 2021-1-E - ORDER NO. 2021-446

JUNE 30, 2021

IN RE:	Annual Review of Base Rates for Fuel Costs of Duke Energy Progress, LLC	) ORDER APPROVING) ADJUSTMENT IN FUEL) COST RECOVERY) FACTORS AND) STIPULATION

I. INTRODUCTION

As established in section 58-27-865 of the South Carolina Code of Laws (2015), the Public Service Commission of South Carolina (Commission) conducted an annual review of the base rates for fuel costs of Duke Energy Progress, LLC (DEP or Company) to determine whether any adjustment in the fuel cost recovery factors is appropriate. The Commission finds the adjustments in fuel costs set forth in the Stipulation entered into among DEP, the Office of Regulatory Staff (ORS), the Southern Alliance for Clean Energy (SACE), the South Carolina Coastal Conservation League (SCCCL), and Nucor Steel—South Carolina (Nucor) are reasonable. Accordingly, the Commission approves the adjustments and the Stipulation.

II. PROCEDURAL HISTORY

On December 14, 2020, the Clerk's Office of the Commission provided Notice of Hearing and Prefile Testimony (Notice) instructing DEP to publish Notice in newspapers of general circulation by March 3, 2021 and to provide Proof of Publication by March 23, 2021. This Notice also instructed the Company to furnish Notice to each affected customer on or before March 3, 2021, and to provide certification to the Commission that Notice had been furnished by March 23, 2021. The Notice also advised that the annual review of base rates for fuel costs of DEP would begin with a hearing occurring on June 10, 2021. As provided by S.C. Code Ann. Section 58-27-865, this annual proceeding allows "the Commission and all interested Parties to review the fuel purchasing practices and policies of [DEP] and for the Commission to determine if any adjustment in the fuel cost recovery mechanism is necessary and reasonable." *See*, Notice of Hearing and Prefile Testimony Deadlines, dated December 14, 2021.

On March 23, 2021, DEP submitted an affidavit to the Commission attesting it provided, via bill insert, the Notice regarding the hearing to its retail customers in South Carolina during February 2021. DEP also filed affidavits of publication with the Commission on March 24, 2021, proving that DEP published the Notice in newspapers of general circulation within its service territory.

ORS, as an automatic statutory party of record, filed a notice of appearance of counsel.[1] The South Carolina Department of Consumer Affairs (Consumer Affairs) was provided notice of the proceeding pursuant to S.C. Code Ann. Section 37-6-604(C) (Supp. 2020) Consumer Affairs did not intervene or appear. The Commission approved the petitions to intervene of Nucor Steel, SCCCL and SACE. Thereafter, DEP pre-filed the direct testimony of six witnesses, and ORS pre-filed the direct testimony of four witnesses.

On June 10, 2021, a virtual public hearing took place before the Commission as duly noticed, with the Honorable Justin T. Williams, Chairman of the Commission,

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[1] ORS is automatically a party pursuant to S.C. Code Ann. Section 58-4-10(B)(2015).

presiding. Katie M. Brown, Esquire, and Samuel J. Wellborn, Esquire, appeared on behalf of DEP; Robert R. Smith, Esquire, was excused by the Commission at the beginning of the hearing, and Michael K. Lavanga, Esquire, admitted *pro hac vice*,[2] appeared on behalf of Nucor. Kate Lee Mixson, Esquire, appeared on behalf of SCCCL and SACE, and Andrew M. Bateman, Esquire, and Alexander W. Knowles, Esquire, represented the interests of ORS.

ORS presented to the Commission the Stipulation agreed to by all parties and the Commission entered the Stipulation into evidence as Hearing Exhibit 1. Thereafter, DEP and ORS submitted the pre-filed testimonies of all their witnesses. The Commission had an opportunity to question each witness at the hearing. All pre-filed exhibits were admitted without objection and marked as hearing exhibits. The hearing adjourned on June 10, 2021. After the hearing, ORS filed the amended direct testimony of witness Morgan, and DEP filed the amended direct testimony of witness Martin.

III. THE STIPULATION

On June 7, 2021, after the parties pre-filed direct testimony, and after the parties had an opportunity to conduct discovery, ORS filed a seventeen-page Stipulation executed by ORS, DEP, SCCCL/SACE, and Nucor (Stipulating Parties). As to hearing procedure, the Stipulating Parties agreed to enter into the record the direct testimonies and exhibits of all DEP and ORS witnesses and to waive the right of cross-examination, while reserving the right for re-direct.

[2] "For this turn; for this one particular occasion. A lawyer may be admitted to practice in a jurisdiction for a particular case only." (*Black's Law Dictionary*, Fifth edition (1979)).

The Stipulation is attached to and incorporated within this Order as Order Exhibit 1. The following enumerated paragraphs provide a summary of the substantive points the Stipulating Parties agreed upon:

1. "To accept all recommendations and adjustments in the testimony and exhibits of ORS witnesses." (Stipulation, p. 2).
2. "[T]he 2021 component values for the Net Energy Metering ("NEM") Distributed Energy Resources, as shown in Table 5 in the testimony of DEP witness Martin . . . comply with the NEM methodology approved by the Commission in Order No. 2015-194 and satisfy the requirements of S.C. Code Ann. § 58-40-10, *et seq*." (Stipulation, p. 3).
3. "Upon the issuance of the Commission's final order in the generic docket regarding Net Energy Metering (Docket No. 2019-182-E), DEP shall recalculate the DER incentive and other components which may change as a result of that order. DEP shall file its recalculations with the Commission within 30 days of the issuance of the final order and shall provide its recalculation to the parties in this docket. . . . Any difference between the DER incentive and other components approved by the Commission in Docket No. 2021-1-E and the recalculated DER incentive . . . will be reflected in the base fuel and DERP Incremental (over)/under collection as of the effective date of the Order in Docket 2019-182-E, as applicable, and included in the Company's 2022 fuel filing." (Stipulation, p. 4).

4. "The Stipulating Parties agree with the adjustments made by the Company to the DERP incremental costs component," and with the "ending cumulative balances of DERP incremental costs for February 2021 as an under-recovered $173,595, and June 2021 as an under-recovered $274,531 . . . ." (Stipulation, p. 4). The parties also agreed DEP could recover DERP incremental costs for service provided from July 1, 2021, through June 30, 2022, in the amounts of $1 per month for residential customers, $3.53 per month for commercial customers, and $100 per month for industrial customers. (Stipulation pp. 4-5).
5. "[U]nder-collected DERP incremental costs resulting from the annual cost caps mandated by Act 236 will earn carrying cost at the three-year treasury rate plus 65 basis points and will be reallocated using each class's contribution to peak demand." (Stipulation, p. 5). Furthermore, DEP will provide to ORS "and, where appliable, its customers" forecasts of the expected DERP [c]harge to be set at its next annual fuel proceeding . . . and DEP's forecast of DERP incremental and avoided costs." (Stipulation, p. 5).
6. The Stipulating parties agree with the ending cumulative balances of DERP avoided costs for February 2021 as an over-recovered $19,309, and June 2021 as an over-recovered $36,805, as calculated by the Company." (Stipulation, p. 6).
7. The parties agree with the adjustments to the base fuel component made by DEP, and "agree with the ending cumulative balances of base fuel for February

2021 as an under-recovered $10,892,003, and June 2021 as an under-recovered $9,257,175 . . . ." (Stipulation, p. 6).

8. The parties "agree with the ending cumulative balances of environmental costs for February 2021 as an over-recovered $348,874, and June 2021 as an over-recovered $483,868 . . . ." (Stipulation, p. 6).

9. The parties "agree with the ending cumulative balances of capacity costs for February 2021 as an under-recovered $5,044,753, and June 2021 as an under-recovered $5,491,437 . . . ." (Stipulation, p. 6).

10. The parties agree with the fuel factors in the chart below and that those factors are consistent with section 58-27-865. (Stipulation, pp. 7-8).

Class of Service	Base Fuel Component (¢/kWh)	Environmental Component (¢/kWh)	Capacity Related Component (¢/kWh)	DERP Avoided Cost Component (¢/kWh)	Combined Total Fuel Factor (¢/kWh)
Residential[3]	1.887	0.005	0.465	0.003	2.360
General Service (non-demand)	1.874	0.015	0.580	0.004	2.473
General Service (demand)	1.874	[4]	[5]	[6]	1.874
Lighting	1.874	0.000	0.000	0.000	1.874

11. Regarding plant outages that were not complete by February 28, 2021, and plant outages where final reports or investigations were not available, the parties "agree that they retain the right to review the reasonableness of plant outage(s)

[3] The Residential Base Fuel Factor includes the Residential Energy Conservation Discount, Rider RECD-2D, adjustment factor of 0.7068%
[4] The Proposed General Service (demand) Environmental Component is 4 cents per kW.
[5] The Proposed General Service (demand) Capacity Related Component is 157 cents per kW.
[6] The Proposed General Service (demand) DERP Avoided Cost Component is l cent per kW.

and associated costs in the review period during which the outage is completed or when the report(s) become available." (Stipulation, p. 8).

12. DEP will provide to ORS, "and where applicable, its other customers," certain reports, including monthly fuel reports showing over and under recovery balances in the forecast period, and quarterly forecasts of the expected fuel factor to be set at the next annual fuel proceeding. The quarterly forecasts will not occur in the quarter in which DEP makes its annual fuel filing. (Stipulation, p. 9).
13. The parties agree the methodology used by DEP to calculate the environmental cost component and the capacity-related cost component of the fuel factor is consistent with section 58-27-865. (Stipulation, p. 10).

IV. EVIDENCE PRESENTED AT THE HEARING

DEP offered the pre-filed direct testimonies and any accompanying exhibits of Kevin Houston, Ben Waldrep, Brett Phipps, Bryan Walsh, Jason D. Martin, and Dana M. Harrington.

Kevin Houston, DEP Manager of Nuclear Fuel Supply, with responsibility for nuclear fuel procurement, testified to the Company's fuel purchase practices, the cost of fuel expended by DEP in the review period, and cost changes expected in the billing period.[7] (Tr. p. 15.2, lines 5, 8, p. 15.3, lines 7-10). Houston testified DEP uses long-term contracts for purchasing uranium and that "[b]y staggering long-term contracts over time

[7] The Review Period extended from March 1, 2020, through February 28, 2021 (Review Period). The Billing Period extends from July 1, 2021, through June 30, 2022. (*See* Tr. p. 15.3, lines 8-10).

for these components of the nuclear fuel cycle, DEP's purchases within a given year consist of a blend of contract prices negotiated at many different periods in the markets, which has the effect of smoothing out DEP's exposure to price volatility." (Tr. p. 15.5, lines 14-17). Houston further described this process as the "portfolio approach to contracting." (Tr. p. 15.6, line 7). More specifically, Houston stated the average cost per pound of uranium concentrates cost 11% less than the previous year's review period, although the cost of enrichment services purchased by DEP increased by 22%. (Tr. p. 15.6, lines 10-11, 14-15). He further testified DEP "anticipates a decrease in nuclear fuel costs on a cents per kilowatt hour ("kWh") basis through the next billing period" "from 0.587 cents per kWh incurred in the review period, to approximately 0.582 cents per kWh in the billing period." (Tr. p. 15.7, lines 15-16, p. 15.8, lines 1-2).

Ben Waldrep, Senior Vice President of Nuclear Operations at DEP, discussed the performance, during the review period, of three of DEP's nuclear power stations—Brunswick, Harris, and Robinson. (Tr. p. 21, lines 18-19, p. 24, lines 3-6). This fleet is comprised of the three generating stations, containing four units, as Robinson has two units. (Tr. p. 27.4, lines 10-18). Waldrep provided an overall statement of how DEP's nuclear stations performed while producing about half of the power for the Company: "DEP operated its nuclear stations in a reasonable and prudent manner during the review period and achieved an actual net nuclear capacity factor of 93.13 percent while providing approximately 49.5 percent of the total power generated by DEP." (Tr. p. 24, lines 10-14).

Waldrep informed the Commission DEP disconnected both the Brunswick Unit 1 and the Robinson stations during the review period for scheduled, refueling outages. (Tr.

p. 27.9, lines 18-19, p. 27.9, line 12). He noted while the Brunswick Unit 1 refueling outage went well, "[t]he outage extended 3 days beyond the scheduled allocation primarily due to emergent challenges with the 'F' safety relief pilot valve. As the unit was heating up and preparing to exit the refueling outage, the pilot valve failed to seat during testing. Repair of the pilot valve required the reactor to be shut down." (Tr. p. 27.9, lines 7-11). Somewhat similarly, the scheduled refueling outage at Robinson went well until the outage required extension "primarily driven by emergent challenges with containment sump level and rod control malfunctions." (Tr. p. 27.10, lines 4-7).

As to outages of DEP's nuclear stations for reasons other than refueling, Waldrep testified Brunswick Unit 1 required a maintenance outage to remove "failed fuel." (Tr. p. 27.10, lines 10-11). Ultimately the station required disconnection for ten days to replace a "failed bundle," but the "root cause of the fuel failure is in progress." (Tr. p. 27.10, lines 12-14). Waldrep explained the uncertainty in finding the cause of the fuel failure: "it's potentially a manufacturing issue, it's potentially a foreign material issue," and "[w]e'll have to decide do we work with the vendor to kind of co-fund development of this technique [to determine a cause]." (Tr. p. 42, lines 9-12, 18-20).

After the fuel failure incident, DEP disconnected Brunswick Unit 1 again "due to a ground on the main generator," requiring an outage of eighteen days. (Tr. p. 27.10, lines 16-17). Waldrep explained a "ground" is "when you have an electrical current that gets where it's not supposed to be . . . And we have very sensitive equipment that detects subtle grounds. So you can think of it as electricity leaking where you don't want it." (Tr. p. 31, lines 10-18). Waldrep also notified the Commission Brunswick Unit 2 experienced two short outages, each lasting less than twenty-four hours, "to address failing no load disconnect switch phases." (Tr. p. 27.11, lines 1-3).

Finally, Waldrep testified the Harris station experienced three non-refueling outages. (Tr. p. 27.11, lines 9, 13-15). Waldrep noted the Harris station "was forced offline for 2 days due to a loss of hydraulic control header pressure," explaining "while plant personnel appropriately followed all applicable procedures, a procedure was flawed based on erroneous information provided by a vendor." (Tr. p. 27.11, lines 9-12). Waldrep also reported Harris experienced an outage for two and one-half days "when a control rod dropped during testing" and a six-day outage when "a generator lockout resulted from a nonsegregated bus failure." (Tr. p. 27.11, lines 13-15).

In response to questions from the Commission at the hearing as to whether DEP had concerns about Brunswick Unit 1 having the "highest average forced-outage factor in the fleet," Waldrep responded: "Well, we are certainly not satisfied with the results that we achieved in 2020." (Tr. p. 29, lines 19-24). The Commission also noted "the Brunswick unit average net capacity was 84.36 percent . . . less than the capacity factor." (Tr. p. 40, lines 12-14). Waldrep asserted the Company has instituted "robust corrective actions" and is working to improve reliability, not only at Brunswick but throughout the fleet. (Tr. p. 29, lines 24-25, p. 30, lines 1-22). He also noted these outages were "atypical" (Tr. p. 40, line 20) and assured the Commission:

> I'm confident that the fixes we're putting in place are fixes to last. When you look at the work we're doing with the fuel, with the work we're doing in the electrical system, the pump refurbishments, there's a tremendous amount of work going on at Brunswick right now to maintain equipment the way it

> needs to be, and we're getting full company support to be able to make those upgrades.

(Tr. p. 33, lines 2-9).

Brett Phipps, non-nuclear fuel procurement director for DEP, testified regarding the Company's fossil fuel costs for the review period (March 1, 2020, to February 28, 2021) and the billing period (July 1, 2021, to June 30, 2022). (Tr. p. 44, lines 19-20, p. 46, lines 7-11). Phipps summarized the cost of coal and gas, noting a 12% increase in the cost of coal and a decrease of 2% in the cost of gas in this review period compared to the last review period. (Tr. p. 46, lines 12-15, lines 23-25, p. 47, line 1). He further testified, "[c]oal markets continue to be distressed" and have "increased market volatility," whereas "the nation's natural gas supply has grown significantly over the last several years and producers continue to enhance production techniques, enhance efficiencies, and lower production costs." (Tr. p. 50.5, line 22, p. 50.6, lines 11-13).

Phipps also explained the impact the COVID-19 pandemic had on DEP's operations, noting "the company experienced a significant shift in generation from coal to natural gas" and "required inventory mitigation beyond the Company's typical no-cost mitigation measures." (Tr. p. 47, lines 11-22). Therefore, "the company was required to evaluate alternatives to reduce its coal contract obligations that exceeded its consumption and storage capabilities." (Tr. p. 47, line 24 - p. 48, line 2). The most cost-effective plan, the Company determined, was to pursue "contractual buyouts," rather than "to force-run coal generation," which resulted in "a projected customer savings of approximately $22 million." (Tr. p. 48, lines 7-18).

Bryan Walsh, Vice President of Central Services and Organizational Effectiveness for DEP's subsidiary, Duke Energy Business Services, testified to the performance of DEP's fleet of fossil, hydroelectric, and solar facilities, noting these facilities produce half of DEP's power generation. (Tr. p. 62.2, lines 5-9, p. 62.3, lines 13-18, p. 62.6, lines 8-10). Walsh testified: "[t]he company's generating units operated efficiently and reliably during the review period." (Tr. p. 60, lines 12-13). Walsh also discussed outages at the facilities and emission reduction actions. (Tr. p. 62.9, line 4 - p. 62.11, line 6).

Jason Martin testified before the Commission as the director responsible for "the development and execution of strategy and policy support related to distributed energy technology," to explain the Distributed Energy Resource Program (DERP) costs. (Tr. p. 68.2, lines 5-9, p. 68.3, lines 2-3). Martin relayed DEP "incurred DERP incremental and avoided costs totaling $4,444,255 in the [review period]; anticipates incurring $1,764,598 during the [estimated period]; and projects to incur $5,408,406 in the [billing period]."[8] (Tr. p. 68.4, lines 4-8). Martin included in his testimony a DEP DERP cost summary, citing DEP witness Harrington's exhibits:

[8] Review Period: March 1, 2020, through February 28, 2021; Estimated Period: March 1, 2021, through June 30, 2021; Billing Period: July 1, 2021, through June 30, 2022. (Tr. p. 68.4, ll. 5-8).

Table 2: DEP DERP Cost Summary - Review, Estimated, and Billing Periods

Cost Type	Review Period 3/1/20-2/28/21	Forecast Period 3/1/21-6/30/21	Billing Period 7/1/21-6/30/22
DERP Incremental Costs			
Purchased Power Agreements	$ 44,435	$ 13,956	$ 34,523
DER NEM Incentive	1,674,325	710,088	2,303,298
Solar Rebate Program - Amortization	587,885	206,052	657,479
Solar Rebate Program - Carrying Costs	483,009	159,880	491,637
Shared Solar Program	57,591	16,650	44,745
NEM Avoided Capacity Costs	18,454	1,883	6,285
NEM Meter Costs	125,799	46,024	143,917
General and Administrative Expenses	301,384	127,577	358,001
Interest on under-collection due to cap	314	119	530
Total DER Incremental Costs	$ 3,293,196	$ 1,282,229	$ 4,040,415
DERP System Avoided Cost - Energy & Capacity			
Purchased Power Agreements	$ 1,066,069	$ 448,029	$ 1,268,827
Shared Solar Program	84,990	34,340	99,164
Total DERP Avoided Costs	$ 1,151,059	$ 482,369	$ 1,367,991
Total Incremental and Avoided Cost	$ 4,444,255	$ 1,764,598	$ 5,408,406

Sources
Incremental Costs: Harrington Exhibit 9 & 11
Avoided Costs: Harrington Exhibit 13 & 14

(Tr. p. 68.5, line 1).

Martin went on to testify to the components of net energy metering (NEM) distributed energy resources, and states: "[t]he calculation is consistent with the methodology approved in Order No. 2015-194. (Tr. p. 68.8, lines 1-2). Martin's Table 5 sets forth the components of NEM distributed energy resources:

Table 5: Value of NEM Distributed Energy Resource, by Component

Components of NEM Distributed Energy Resource Value	Component Value ($/kWh) Residential PV[1]	Component Value ($/kWh) SGS PV[1]	Component Value ($/kWh) Large PV[1]
Marginal Energy Cost	$0.024785	$0.024795	$0.024801
Marginal Capacity Cost	$0.001767	$0.001738	$0.001763
Ancillary Services	($0.002389)	($0.002390)	($0.002390)
Transmission and Distribution ("T&D") Capacity	$0.000000	$0.000000	$0.000000
Avoided Criteria Pollutants[2]	$0.000027	$0.000028	$0.000030
Avoided CO2 Emission Cost (currently zero)	$0.000000	$0.000000	$0.000000
Fuel Hedge[3]	$0.000000	$0.000000	$0.000000
Utility Integration & Interconnection Costs	$0.000000	$0.000000	$0.000000
Utility Administration Costs	$0.000000	$0.000000	$0.000000
Environmental Costs	$0.000000	$0.000000	$0.000000
Subtotal	**$0.024190**	**$0.024170**	**$0.024204**
Line Losses[4]	$0.000272	$0.000271	$0.000271
Total Value NEM Distributed Energy Resource	**$0.024461**	**$0.024442**	**$0.024475**

1 "Residential PV" refers to a load shape reflecting generation installed by a residential customer. "SGS PV" refers to a load shape reflecting generation installed by a small commercial/industrial customer served under Small General Service Schedule SGS. "Large PV" refers to a load shape reflecting generation installed by a customer with higher consumption requirements and applies to all other nonresidential schedules. For the first time, the Company has separated the values for residential customers ("Residential PV") and small commercial/industrial customers ("SGS PV") as a result of available actual metered solar load profile data for the residential class. The Company continues to utilize third-party solar load profile data for non-residential customers.

2 Avoided Criteria Pollutants reflects NOx and SOx that have been separately identified from approved marginal energy costs.

3 Pursuant to the Settlement Agreement reached in DEP's 2016 annual fuel proceeding (Docket No. 2016-3-E), the Company has calculated the hedge value and determined that no fuel hedge exists; therefore, the value is zero.

4 Line loss factors are 1.281% for marginal energy and 1.857% for marginal capacity per DEP's updated 2018 line loss analysis based upon 2020 cost of service.

(Tr. p. 68.8, line 4).

DEP's last witness, Dana Harrington, a Rates Manager for DEP, testified to "DEP's actual fuel, capacity-related costs[,] including Public Utility Regulatory Policies Act of 1978 ("PURPA") capacity, environmental, and [DERP] cost data for [the review period], the estimated fuel, capacity-related costs, environmental, and DERP cost information for [the estimated period], and DEP's proposed fuel factors by customer class for [the billing period]."[9] (Tr. p. 78.2, lines 2, 5, 22-23, p. 78.3, lines 1-5).

[9] Review Period: March 1, 2020-February 28, 2021; Estimated Period: March 1, 2021-June 20, 2021; Billing Period: July 1, 2021-June 30, 2022. (*See* Tr. p. 78.3, lines 1-5).

Harrington explained the information and data she shared in her testimony "were taken from DEP's books and records. These books, records, and reports of DEP are subject to review by the appropriate regulatory agencies in the three jurisdictions that regulate DEP's electric rates," and, she stated, "independent auditors" and "internal accounting controls" contributed to the accuracy of the calculations. (Tr. p. 78.3, lines 10-16).

Harrington provided an exhibit, as set forth below, showing a summary of all of DEP's proposed fuel rate components for the billing period. (Tr. p. 78.4, lines 12-13).

DUKE ENERGY PROGRESS, LLC SOUTH CAROLINA RETAIL FUEL CASE CALCULATION OF TOTAL FUEL COMPONENT BILLING PERIOD JULY 1, 2021 TO JUNE 30, 2022				Exhibit 1 DOCKET NO. 2021-1-E
	Customer Class			
	Cents / kWh			
Description	Residential	General Service (non-demand)	Lighting	General Service (demand)
Base Fuel Costs				
Base Fuel Cost Component (Over) / Under Recovered Balance as of June 30, 2021	0.139	0.139	0.139	0.139
Base Fuel Cost Component Projected Billing Period	1.735	1.735	1.735	1.735
Total Base Fuel Cost Component	1.874	1.874	1.874	1.874
Total Base Fuel Cost Component Increased for RECD	1.887			
Capacity Related Cost	Cents / kWh			Cents / kW
Capacity Related Cost Component (Over) / Under Recovered Balance as of June 30, 2021	0.046	0.114	0.000	45
Capacity Related Cost Component Projected Billing Period	0.416	0.466	0.000	112
Total Capacity Related Cost Component	0.462	0.580	0.000	157
Total Capacity Related Cost Component Increased for RECD	0.465			
Distributed Energy Resource Program (DERP) Avoided Costs	Cents / kWh			Cents / kW
DERP Avoided Cost (Over) / Under Recovered Balance as of June 30, 2021	0.000	0.001	0.000	0
DERP Avoided Costs Projected Billing Period	0.003	0.003	0.000	1
Total DERP Avoided Cost Component	0.003	0.004	0.000	1
Total DERP Avoided Cost Component Increased for RECD	0.003			
Environmental Costs	Cents / kWh			Cents / kW
Environmental Component (Over) / Under Recovered Balance as of June 30, 2021	(0.015)	(0.008)	0.000	(1)
Environmental Component Projected Billing Period	0.020	0.023	0.000	5
Total Environmental Component	0.005	0.015	0.000	4
Total Environmental Cost Component Increased for RECD	0.005			
Total Fuel Cost Factor - Cents/ kWh	2.360	2.473	1.874	1.874
Total Demand Fuel Cost Factor - Cents/ kW				162
	Dollars			
Distributed Energy Resource Program Incremental Cost per Account	Residential	Commercial		Industrial
DERP Incremental (Over) / Under Recovered Balance as of June 30, 2021				
Annual Charge	$ 0.92	$ 2.49		$ 195.31
Monthly Charge	$ 0.08	$ 0.21		$ 16.28
DERP Incremental Projected Billing Period				
Annual Charge	$ 12.62	$ 39.67		$ 3,027.52
Monthly Charge	$ 1.05	$ 3.31		$ 252.29
Total DERP Annual Charge - Excluding GRT	$ 11.94	$ 42.16		$ 1,193.60
Total DERP Monthly Charge - Excluding GRT	$ 0.99	$ 3.51		$ 99.47
Total DERP Annual Charge -Including GRT	$ 12.00	$ 42.39		$ 1,200.00
Total DERP Monthly Charge - Including GRT	$ 1.00	$ 3.53		$ 100.00

(Tr. p. 78.5, line 3).

Harrington advised the Commission she believed DEP's actual fuel costs during the review period "were reasonable" and "met the criteria set forth in S.C. Code Ann. § 58-27-865." (Tr. p. 78.15, lines 13-14). She further stated: "These costs also reflect DEP's continuing efforts to maintain reliable service and an economic generation mix, thereby minimizing the total cost of providing service to DEP's South Carolina retail customers." (Tr. p. 78.15, lines 14-16). Likewise, Harrington testified DEP's actual distributed energy resource program costs were reasonable and comply with section 58-39-130 (A)(2). (Tr. p. 78.15, lines 19-20). As to the impact on a customer's bill, should the Commission approve DEP's fuel costs, Harrington testified:

> The impact of all components of this filing to customers' monthly bills on an average Residential customer using 1,000 kWh per month is a decrease of $0.97, or 0.9 percent. The average decrease seen in the average monthly bill of Lighting customers is 0.1 percent, and the average increase seen in the average monthly bill of General Service Non-demand and General Service Demand customers is 1.5 percent, and 1.0 percent, respectively.

(Tr. p. 78.16, lines 17-21).

ORS offered the pre-filed direct testimonies and any accompanying exhibits of Anthony Briseno, Brandon Bickley, O'Neil Morgan, and Michael Seaman-Huynh. Briseno, ORS Audit Manager, presented the results of ORS's review of the books and examination of the fuel costs of DEP. (Tr. p. 83, lines 17-18, p. 85, lines 10-14). Briseno informed the Commission ORS "agrees with the balances and the adjustments as put forth by the Company for the 12-month review period that ended February 2021." (Tr. p. 85, lines 21-23). Briseno explained ORS verified DEP's expenses for fuel and "recomputed" and "recalculated" the costs and adjustments of the Company. (Tr. pp. 87.3 - 87.10). In summary, ORS found DEP's accounting practices to be in keeping with Commission orders and applicable statutes and "ORS agrees with the following cumulative (over)/under-recovery balances as calculated in Company witness Harrington's Exhibits in this docket":

- February 2021 base fuel cost under-recovery balance of $10,892,003;
- February 2021 environmental cost component over-recovery of $348,874;
- February 2021 capacity cost component under-recovery balance of $5,044,753;
- February 2021 DERP incremental under-recovery balance of $173,595;
- February 2021 DERP avoided cost over-recovery balance of $19,309;
- June 2021 estimated base fuel cost under-recovery balance of $9,257,175;
- June 2021 estimated environmental cost component over-recovery balance of $483,868;
- June 2021 estimated capacity cost component under-recovery balance of $5,491,437;
- June 2021 estimated DERP incremental cost under-recovery balance of $274,531; and,
- June 2021 estimated DERP avoided cost over-recovery balance of $36,805.

(Tr. p. 87.18, lines 1-13).

Brandon Bickley, a regulatory analyst in the Energy Operations Division of ORS, reviewed whether DEP "efficiently operated its plants and made every reasonable effort to minimize fuel costs so as to provide reliable and high-quality service to its customers." (Tr. p. 94.1, lines 10-11, p. 94.2, lines 23-25). Of the ORS review, Bickley informed the Commission ORS examined DEP documents and analyzed its data, but also met with DEP personnel and attended Nuclear Regulatory Commission meetings regarding the Harris, Brunswick, and Robinson nuclear plants. (Tr. p. 94.3, lines 5-17). Based upon its examination and review, Bickley testified: "ORS does not recommend any adjustments to the Fuel Factors based on the Company's power plant operations." (Tr. p. 94.6, lines 13-14).

O'Neil Morgan, Senior Engineer in ORS's Utility Rates and Services Division, testified to ORS's review of DEP's DERP expenses. (Tr. p. 101.1, lines 10-11, p. 101.2, lines 14-18). Morgan explained statutory law allows an electrical utility to "recover associated [DERP] costs that are reasonably and prudently incurred." (Tr. p. 101.3, lines 1-2). Furthermore, "payments for electricity provided under the DERP that are paid at avoided cost rates or rates negotiated pursuant to the Public Utility Regulatory Policy Act of 1978 ("PURPA"), whichever is lower, are eligible to be recovered through the DERP avoided cost component." (Tr. p. 101.3, lines 10-13). Morgan stated: "ORS found the Company's DERP avoided and incremental costs to be reasonably and prudently incurred in implementing the Company's DERP. ORS also reviewed the Company's estimated and forecasted DERP avoided and incremental costs and found them to be reasonable." (Tr. p. 101.4, lines 10-13). Finally, Morgan noted "ORS recommends the Commission accept the Company's proposed updates to SC Rider RNM-9 (Martin Amended Exhibit 1)." (Tr. p. 101.6, lines 14-15).

ORS's final witness, Michael Seaman-Huynh, Deputy Directory of Energy Operations at ORS, testified to ORS's review of DEP's fuel costs. (Tr. p. 107.1, lines 9-11, p. 107.2, lines 13-16). Seaman Huynh advised: "ORS does not recommend any adjustments to the Company's proposed fuel factors based on the Company's historical and forecasted fuel expenses and customer sales." (Tr. p. 107.6, lines 15-16). As to the components of DEP's proposed fuel factors and the effect these factors will have on classes of customers, Seaman-Huynh provided the following exhibit:

Office of Regulatory Staff
Proposed Fuel Factors
Duke Energy Progress, LLC
Docket No. 2021-1-E

EXHIBIT MSH-5

	Proposed Proposed Fuel Factors (¢/kWh)				
Customer Class	**Base Fuel Component**	**Environmental Component**	**Capacity Related Component**	**DERP Avoided Cost Component**	**Total Fuel Factor**
Residential [1]	1.887	0.005	0.465	0.003	2.360
General Service (non-demand)	1.874	0.015	0.580	0.004	2.473
General Service (demand)	1.874	- [2]	- [3]	- [4]	1.874
Lighting	1.874	0.000	0.000	0.000	1.874

[1] The Residential Base Fuel Factor includes the Residential Energy Conservation Discount, Rider RECD-2C, adjustment factor of 0.7068%.
[2] The Proposed General Service (demand) Environmental Component is 4 cents per kW.
[3] The Proposed General Service (demand) Capacity Related Component is 157 cents per kW.
[4] The Proposed General Service (demand) DERP Avoided Cost Component is 1 cent per kW.

(Hearing Exhibit 11, MSH-5).

Seaman-Huynh responded to questions from the Commission regarding the coal contract buyout DEP engaged in due to its surplus of coal during the pandemic, clarifying ORS "concluded that the company did act reasonably." (Tr. p. 108, lines 23-24). He assured the Commission: "We reviewed the company's reasoning for having to use those provisions in its coal contracts for buyouts. We discussed the matter with the company, and we reviewed the calculations that the company had regarding the $22 million." (Tr. p. 108, lines 18-22). Seaman-Huynh answered affirmatively when asked whether ORS concluded the coal buyout was less impactful for the customer than receiving and burning the coal. (Tr. p. 109, lines 5-8).

This ORS witness also explained the rationale behind ORS's recommendation DEP provide data quarterly regarding its projected fuel rates, testifying:

> Commissioner, I would say that this will provide additional information throughout the year, not just to the Commission and to ORS, but to other parties, as well. Specifically, I'm thinking about Nucor Steel, which has a — as you know, is one of the company's largest South Carolina customers, with significant operations in the State and a large budget, which includes a large amount of energy. This reporting will allow the Commission and ORS, as well as the other parties, including Nucor, to get a feel for or be able to see how the company's fuel rates — forecasted fuel rates or projected fuel rates for the next fuel hearing — what those numbers could be, provide an updated forecast to allow for budgeting, to allow for — specifically, for Nucor to be able to budget, to allow for ORS to raise questions throughout the year should we see a forecasted rate to increase or decrease beyond what expectations could be, to address those prior to the next annual fuel hearing with the company sometime during the year. And, of course, it provides the — the Commission with information on what to potentially expect in next year's annual fuel proceeding.

(Tr. p. 110, line 14 - p. 111, line 9).

V. FINDINGS OF FACT

Based on the testimony and exhibits received into evidence at the hearing and the entire record of these proceedings, the Commission hereby makes the following findings of fact:

1. DEP, ORS, SCCCL/SACE, and Nucor entered into a Stipulation, filed with the Commission on June 7, 2021, addressing all issues in this docket.

2. Among other points, the Stipulating Parties agreed to accept all fuel cost factors and adjustments established by DEP.

3. The evidence supports the calculations of fuel cost adjustments set forth in the testimony of DEP witnesses Harrington and Martin and ORS witnesses Morgan, Briseno and Seaman-Huynh.

4. The evidence supports the finding DEP's fuel procurement practices were reasonable as set forth in the testimony of DEP witnesses Phipps and Houston and ORS witness Seaman-Huynh.

5. The evidence supports the finding DEP did not incur fuel costs due to a failure to make every reasonable effort to minimize fuel costs as set forth in the testimony of DEP witnesses Phipps and Waldrep and ORS witness Bickley.

6. The evidence from all witnesses supports the NEM Distributed Energy Resource values, the DERP avoided cost components, the capacity-related components, the environmental components, fuel costs and expenses, and DEP's revisions to the 2021 Renewable Net Metering Rider RNM tariff sheet attached as Order Exhibit 2, all as set forth in the Stipulation.

7. ORS recommended DEP "will provide to the ORS, and where applicable, its other customers" [in addition to monthly fuel recovery reports and forecasts of the expected DERP charge] certain quarterly forecasts as more fully stated below:

> Quarterly forecasts (during each of the three (3) quarters in which there is no annual fuel proceeding but not in the quarter where DEP makes its annual fuel filing) of the expected fuel factor to be set at its next annual fuel proceeding based upon DEP's historical (over)/under recovery to date and DEP's forecast of prices for uranium, natural gas, coal, oil and other fuel required for generation of electricity. DEP agrees that it will use commercially reasonable efforts in making these forecasts. To the extent that the forecast data required hereunder is confidential, any party or customer that wants forecasted fuel data will have to sign a non-disclosure agreement to protect the data from public disclosure and to only disclose it to employees or agents with a need to be aware of this information.

(Stipulation, page 9, paragraph B.17(c)).

8. No intervenor or party challenged or disagreed with the fuel factors or adjustments reported by DEP.

9. The Commission reviewed the testimony and exhibits of all parties and held a public hearing as duly noticed.

10. Based upon a review of the testimony and exhibits presented by DEP, the testimony and exhibits of ORS, the Stipulation agreed to by DEP, ORS, SCCCL/SACE and Nucor, and noting the absence of any evidence presented contrary to the evidence in the record, we find and accept the fuel factors and adjustments, the tables and calculations, and the revised 2021 Renewable Net Metering Rider RNM tariff sheet as accurate.

11. The Commission further finds the revisions to the 2021 Renewable Net Metering Rider RNM tariff sheet as Hearing Exhibit 6[10] (Martin Amended Exhibit 1) are lawful, just, and reasonable.

VI. LAW/ANALYSIS

"The Commission may, upon petition . . . ascertain and fix just and reasonable standards, classifications, regulations, practices, or service to be furnished, imposed, observed, and followed by any or all electrical utilities." S.C. Code Ann. § 58-27-140(1) (2015). All rates the Commission approves must be both just and reasonable: "Every rate made, demanded or received by any electrical utility . . . shall be just and reasonable." § 58-27-820. As further noted by our supreme court in *S.C. Cable Television Association v. Public Service Commission*: "[t]he just and reasonable rate is set by balancing the interests

[10] Order Exhibit 2 is Amended Exhibit 1 to Jason Martin's Direct Testimony which was pre-filed on June 8, 2021, which is DEP's 2021 Renewable Net Metering Rider RNM tariff sheet and Hearing Exhibit 6.

of the ratepayers and the right of the utility to earn a fair return." 313 S.C. 48, 51, 437 S.E.2d 38, 39 (1993).

While the Commission is vested with the authority and power to "ascertain and fix just and reasonable standards," the ORS is charged with the investigatory component of reviewing an electrical utility: "[t]he Office of Regulatory Staff may investigate and examine the condition and management of electrical utilities or any particular electrical utility." § 58-27-160. Furthermore, it is within ORS's authority to inspect the property and to review the books and records of an electrical utility: "[t]he Office of Regulatory Staff has the right at any and all times to inspect the property, plant, and facilities of any electrical utility and to inspect or audit at reasonable times the accounts, books, papers, and documents of any electrical utility." § 58-27-190.

Following statutory amendments in 2004 altering the structure and operation of the Commission, "[t]he PSC's powers with regard to ratemaking were not eliminated, however. The PSC retained its powers 'to supervise and regulate' rates and service and 'to fix just and reasonable standards, classifications, regulations, practices, and measurements of service." *Utilities Services of South Carolina, Inc.* v. *S.C. Office of Regulatory Staff*, 392 S.C. 96, 105, 708 S.E.2d 755, 760 (2011) (citing S.C. Code Ann. § 58-3-140(A)). The court went on to state: "Accordingly, the PSC may determine that some portion of an expense actually incurred by a utility should not be passed on to consumers." *Id.* The *Utilities Services* opinion continued: "The PSC is not bound by ORS's determination that an expenditure was reasonable and proper for inclusion in a rate application." *Id.* at 106, 708 S.E.2d at 761. The Commission is charged with serving as the ultimate fact-finder:

"the PSC has retained its role as the ultimate fact-finder. As such, it may consider all evidence before it and it does not serve as a 'rubber stamp' for ORS's recommendations." *Id.* at 115, 708 S.E.2d at 765.

The process by which the Commission annually reviews the base rates for fuel costs is established in section 58-27-865. This Code section provides the procedure for the review and recovery of fuel costs and of the incremental costs and avoided costs of distributed energy resource programs (DERP) and net energy metering (NEM) pursuant to chapters 39 and 40 of title 58. The impetus of section 58-27-865, according to the Legislature, was to give an electrical utility the opportunity "to make routine, annual adjustments in the amount of fuel cost recovered from customers" and to promote the public interest "by allowing the recovery of variable and incremental power supply costs on an accurate, timely, and efficient basis." (*See* Editor's Note to § 58-27-865, citing 2007 Act No. 16, § 1.(C).).

Fuel costs are defined in section 58-27-865 as follows:

> The term "fuel cost" as used in this section includes the cost of fuel, cost of fuel transportation, and fuel costs related to purchased power. "Fuel cost" also shall include [certain variable environmental costs] . . . . Upon application of the utility, and after a hearing at which all interested parties may appear and present evidence, the commission may, if it determines such action to be just and reasonable, allow the variable costs of other environmental reagents, other environmental allowances or emissions-related taxes to be recovered as a component of fuel costs, but only to the extent these variable environmental costs are required to be incurred in relation to the consumption of fuel and the air emissions caused thereby. Alternatively, the commission may decide that the costs related to these other variable environmental costs may only be recovered through base rates established under Sections 58-27-860 and 58-27-870.

> All variable environmental costs included in fuel costs shall be recovered from each class of customers as a separate environmental component of the overall fuel factor. The specific environmental component for each class of customers shall be determined by allocating such variable environmental costs among customer classes based on the utility's South Carolina firm peak demand data from the prior year. Fuel costs must be reduced by the net proceeds of any sales of emission allowances by the utility. If capacity costs are permitted to be recovered through the fuel factor, such costs shall be allocated and recovered from customers under a separate capacity component of the overall fuel factor based on the same method that is used by the utility to allocate and recover variable environmental costs. The incremental and avoided costs of distributed energy resource programs and net metering as authorized and approved under Chapters 39 and 40, Title 58 shall be allocated and recovered from customers under a separate distributed energy component of the overall fuel factor that shall be allocated and recovered based on the same method that is used by the utility to allocate and recover variable environmental costs.

§ 58-27-865 (A)(1).

The statute allows for a yearly reconciliation of the actual costs with the costs that were approved the year before:

> The commission shall direct each electrical utility which incurs fuel cost for the sale of electricity to submit to the commission and to the Office of Regulatory Staff, within such time and in such form as the commission may designate, its estimates of fuel costs for the next twelve months. The commission may hold a public hearing at any time between the twelve-month reviews to determine whether an increase or decrease in the base rate amount designed to recover fuel cost should be granted. Upon conducting public hearings in accordance with law, the commission shall direct each company to place in effect in its base rate an amount designed to recover, during the succeeding twelve months, the fuel costs determined by the commission to be appropriate for that period, adjusted for the over-recovery or under-recovery from the preceding twelve-month period. The commission shall direct the

> electrical utilities to send notice to the utility customers with the antecedent billing of the time and place of the public hearings to be held every twelve months, and the commission shall again direct the electrical utilities to send notice to the utility customers with the next billing if the utility is granted a rate increase by the commission.

§ 58-27-865 (B).

The Commission may deny recovery by the utility of any unreasonably incurred fuel costs as described below:

> The commission shall disallow recovery of any fuel costs that it finds without just cause to be the result of failure of the utility to make every reasonable effort to minimize fuel costs or any decision of the utility resulting in unreasonable fuel costs, giving due regard to reliability of service, economical generation mix, generating experience of comparable facilities, and minimization of the total cost of providing service. There shall be a rebuttable presumption that an electrical utility made every reasonable effort to minimize cost associated with the operation of its nuclear generation facility or system, as applicable, if the utility achieved a net capacity factor of ninety-two and one-half percent or higher during the period under review. The calculation of the net capacity factor shall exclude reasonable outage time associated with reasonable refueling, reasonable maintenance, reasonable repair, and reasonable equipment replacement outages; the reasonable reduced power generation experienced by nuclear units as they approach a refueling outage; the reasonable reduced power generation experienced by nuclear units associated with bringing a unit back to full power after an outage; Nuclear Regulatory Commission required testing outages unless due to the unreasonable acts of the utility; outages found by the commission not to be within the reasonable control of the utility; and acts of God. The calculation also shall exclude reasonable reduced power operations resulting from the demand for electricity being less than the full power output of the utility's nuclear generation system. If the net capacity factor is below ninety-two and one-half percent after reflecting the above specified outage time, then the utility

> shall have the burden of demonstrating the reasonableness of its nuclear operations during the period under review.

§ 58-27-865 (F).

As to DERP, section 58-39-140 (A)(1) allows: All costs paid under avoided cost rates, or negotiated rates pursuant to PURPA, whichever is lower, shall be considered an avoided cost under Section 58-39-120(B) and shall be recovered under Section 58-27-865.

Furthermore,

> [n]othing in [section 58-40-20] prohibits an electrical utility from continuing to recover distributed energy resource program costs in the manner and amount approved by Commission Order No. 2015-194 for customer-generators applying before June 1, 2021. Such recovery shall remain in place until full cost recovery is realized. Electrical utilities are prohibited from recovering lost revenues associated with customer-generators who apply for customer-generator programs on or after June 1, 2021."

§ 58-40-20(I) (Supp. 2020).

VII. CONCLUSIONS OF LAW

1. The Commission is statutorily vested with the authority to annually review an electrical utility's base rates for fuel costs "to determine whether an increase or decrease in the base rate amount designed to recover fuel cost should be granted" pursuant to S.C. Code Ann. § 58-27-865 (2015).

2. This proceeding in Docket No. 2021-1-E complied with the provisions of section 58-27-865.

3. ORS, with statutory authority to audit, inspect, and examine the records, books, facilities and practices of an electrical utility pursuant to section 58-27-160 and 190,

found the fuel factors and adjustments DEP provided were reasonable. No challenge was made to the factors and adjustments by any party or intervenor.

4. After careful review of the testimony, exhibits, and all evidence presented in this docket, we conclude substantial evidence supports the fuel rates and adjustments presented by DEP and agreed to among the Stipulating Parties in the Stipulation, reviewed pursuant to section 58-27-865.

5. The fuel costs incurred by DEP were not the result of DEP's failure to make reasonable efforts to minimize fuel costs as set forth in section 58-27-865 (F).

6. The adjustments in the Stipulation were calculated to allow appropriate recovery by DEP "of all their prudently incurred fuel costs as precisely and promptly as possible, in a manner that tends to assure public confidence and minimize abrupt changes in charges to customers," as set forth in section 58-27-865 (G).

VIII. ORDERING PROVISIONS

IT IS THEREFORE ORDERED:

1. The Stipulation is approved and incorporated into this Order as Exhibit 1. The stipulation, which is incorporated into this Order by reference and attachment, is also found to be reasonable resolution of the issues in this case and to be in the public interest and is hereby adopted and approved. Among other points, we note the net effect of approving the Stipulation and ordering DEP to utilize the adjustments set forth in this order will allow for a decrease in billed charges of $0.97 or 0.9% per month to a residential customer, based on an average 1,000 kWh monthly usage.

2. The fuel purchasing practices, plant operations, and fuel inventory management of DEP related to the historical fuel costs and revenues as of the end of the Review Period are prudent.

3. We adopt and approve the amounts stipulated among the parties consisting of a totally combined fuel factor of 2.360 cents per kWh for residential, 2.473 cents per kWh for non-demand general service, 1.874 cents per kWh for demand general service, and 1.874 cents per kWh for lighting.

4. DEP shall set its Residential base fuel factor at 1.887 cents per kWh (not including applicable environmental, capacity-related, and DERP avoided cost components) effective for service rendered during the Billing Period. The Company shall set its General Service (non-demand), Lighting, and General Service (demand) base fuel factors at 1.874 cents per kWh (not including applicable environmental, capacity-related, and DERP avoided cost components) effective for service rendered during the Billing Period.

5. DEP shall set its environmental component billing factor at 0.005 cents per kWh for the Residential class, 0.015 cents per kWh for the General Service (non-demand) class, 0.0 cents per kWh for Lighting class, and 4 cents per kilowatt ("kW") for the General Service (demand) class for service rendered during the Billing Period.

6. DEP shall set its capacity-related component at 0.465 cents per kWh for the Residential class, 0.580 cents per kWh for the General Service (non-demand) class, 0.0 cents per kWh for Lighting class, and 157 cents per kW for the General Service (demand) class for service rendered during the Billing Period.

7. DEP shall set its DERP avoided cost component at 0.003 cents per kWh for the Residential class, 0.004 cents per kWh for the General Service (non-demand) class, 0.0 cent per kWh for Lighting class, and 1 cent per kW for the General Service (demand) class for service rendered during the Billing Period.

8. DEP shall set its DERP Charge at $1.00/month for the Residential class, $3.53/month for the Commercial class, and $100.00/month for the Industrial class, including Gross Receipts Tax and regulatory fees.

9. DEP shall file the South Carolina Retail Adjustment for Fuel, Capacity-Related, Variable Environmental, and DERP Avoided Capacity Costs Rider; Renewable Net Metering Rider RNM-9 tariff sheet; and all other retail Tariffs with the Commission and a copy with ORS within ten (10) days of receipt of this Order. The revised tariffs should be electronically filed in a text searchable PDF format using the Commission's DMS System (https://dms.psc.sc.gov/). An additional copy should be sent via e-mail to etariff@psc.sc.gov to be included in the Commission's ETariff system (https://etariff.psc.sc.gov). DEP shall provide a reconciliation of each tariff rate change approved as a result of this order to each tariff rate revision filed in the ETariff system. Such reconciliation shall include an explanation of any differences and be submitted separately from the Company's ETariff filing. Each tariff sheet shall contain a reference to this Order and its effective date at the bottom of each page."

10. DEP shall comply with all notice requirements set forth in section 58-27-865.

11. DEP shall continue to utilize the methodology for developing the environmental component billing factor for each rate class to recover "variable environmental costs" under S.C. Code Ann. § 58-27-865(A)(1) approved in Order No. 2007-440. Pursuant to S.C. Code § 58-27-865(A)(1), the avoided capacity component of purchased power costs and other capacity costs that are permitted to be recovered through the fuel factor are to be allocated and recovered from customers under a separate capacity component of the overall fuel factor based on the same method that is used by the utility to allocate and recover variable environmental costs.

12. DEP shall continue to file the monthly reports as previously required.

13. DEP shall provide to ORS, "and where applicable, its other customers" certain quarterly forecasts as agreed to in the Stipulation:

> Quarterly forecasts (during each of the three (3) quarters in which there is no annual fuel proceeding but not in the quarter where DEP makes its annual fuel filing) of the expected fuel factor to be set at its next annual fuel proceeding based upon DEP's historical (over)/under recovery to date and DEP's forecast of prices for uranium, natural gas, coal, oil and other fuel required for generation of electricity. DEP agrees that it will use commercially reasonable efforts in making these forecasts. To the extent that the forecast data required hereunder is confidential, any party or customer that wants forecasted fuel data will have to sign a non-disclosure agreement to protect the data from public disclosure and to only disclose it to employees or agents with a need to be aware of this information.

(Stipulation, page 9, paragraph B.17(c)).

14. DEP shall continue to examine and adjust its natural gas hedging program considering the potentially reduced volatility in the domestic natural gas market. DEP shall also provide monthly natural gas hedging reports to ORS.

15. DEP shall, by rate class, account monthly to the Commission and ORS for the differences between the recovery of fuel costs through billed rates and the actual fuel costs experienced by booking the difference to unbilled revenues with a corresponding deferred debit or credit.

16. DEP shall submit monthly reports to the Commission and ORS of fuel costs and scheduled and unscheduled outages of its generating units with a capacity of 100 megawatts or greater.

17. We adopt and approve the analysis presented by DEP and confirmed by ORS showing the average decrease anticipated in the average monthly bill of Lighting customers is 0.1%, and the average increase in the average monthly bill of General Service Non-demand and General Service Demand customers is 1.5%, and 1.0%, respectively.

18. We adopt and approve the NEM Distributed Energy Resource values stipulated between the parties as follows:

$0.024461 for the Component value ($/kWh) Residential PV

$0.024442 for the Component value ($/kWh) Small PV

$0.024475 for the Component value ($/kWh) Large PV

19. With regard to plant outages not complete as of the end of the Review Period, and plant outages where final reports or investigations (Company, contractor, government reports or otherwise) were not available at the time of the hearing on this matter, the reasonableness of such outages shall be subject to review in the period where such report(s) become available and provided to ORS.

20. DEP's revisions to the 2021 Renewable Net Metering Rider RNM tariff sheet, attached hereto as Order Exhibit 2, are lawful, just, and reasonable and shall become effective for service rendered during the Billing Period.

21. Upon the issuance of the Commission's final order in the generic docket regarding NEM (Docket No. 2019-182-E), DEP shall recalculate the DER incentive and other components which may change as a result of that order. DEP shall file its recalculations with the Commission within thirty (30) days of the issuance of the final order and shall provide its recalculations to the parties in this docket. At that time, parties may propose next steps to account for any differences. Any difference between the DER incentive and other components approved by the Commission in Docket No. 2021-1-E and the recalculated DER incentive and other components reflective of the Commission's order in Docket No. 2019-182-E are to be reflected in the base fuel and DERP Incremental (over)/under collection as of the effective date of the order in Docket No. 2019-182-E, as applicable, and included in DEP's 2022 fuel filing.

22. This Order shall remain in full force and effect until further Order of the Commission.

BY ORDER OF THE COMMISSION:

Justin T. Williams, Chairman
Public Service Commission of
South Carolina

BEFORE

THE PUBLIC SERVICE COMMISSION OF

SOUTH CAROLINA

DOCKET NO. 2021-1-E

June 7, 2021

IN RE: Annual Review of Base Rates for Fuel Costs of Duke Energy Progress, LLC	)))	**STIPULATION**

This Stipulation is made by and among the South Carolina Office of Regulatory Staff ("ORS"), Duke Energy Progress, LLC ("DEP" or the "Company"), South Carolina Coastal Conservation League and Southern Alliance for Clean Energy ("CCL/SACE"), and Nucor Steel–South Carolina (collectively referred to as the "Stipulating Parties" or sometimes individually as a "Stipulating Party").

WHEREAS, the above-captioned proceeding has been established by the Public Service Commission of South Carolina (the "Commission") pursuant to the procedure established in S.C. Code Ann. § 58-27-865, and the Stipulating Parties are parties of record in the above-captioned docket;

WHEREAS, the Stipulating Parties have varying legal positions regarding the issues in this case;

WHEREAS, the Stipulating Parties have engaged in discussions to determine whether a stipulation of the issues would be in their best interests;

WHEREAS, following these discussions the Stipulating Parties have each determined that their interests and the public interest would be best served by stipulating all issues in the above-captioned case under the terms and conditions set forth below:

A. STIPULATION OF TESTIMONY AND WAIVER OF CROSS EXAMINATION

A.1 The Stipulating Parties agree to stipulate into the record before the Commission the pre-filed direct testimony and exhibits of ORS witnesses Anthony D. Briseno, Brandon S. Bickley, Michael L. Seaman-Huynh, and O'Neil O. Morgan without objection or cross-examination by any Stipulating Party. The Stipulating Parties also agree to stipulate into the record before the Commission, without objection or cross-examination by any Stipulating Party, the direct testimony and exhibits of DEP witnesses Dana M. Harrington, Kevin Y. Houston, Ben Waldrep (including Confidential Exhibit No. 3), Jason D. Martin, Brett Phipps, and Bryan P. Walsh.

A.2 The Stipulating Parties reserve the right to engage in re-direct of witnesses as may be necessary to respond to issues raised by the examination of their witnesses by non-signatories to this Stipulation.

A.3 The Stipulating Parties agree that no other evidence will be offered in the proceeding by the Stipulating Parties other than the stipulated testimony and exhibits and this Stipulation with the exception of changes comparable to that which would be presented via an errata sheet or through a witness noting a correction or clarification or by a witness adopting the testimony of another if permitted by the Commission or to answer a question posed by a non-signatory to this Stipulation.

B. STIPULATION TERMS

B.1 The Stipulating Parties agree to the proposal set out immediately below, and this proposal is hereby adopted, accepted, and acknowledged as the agreement of the Stipulating Parties.

B.2 Without prejudice to the position of any Stipulating Party in future proceedings, the Stipulating Parties agree to accept all recommendations and adjustments in the testimony and exhibits of ORS witnesses.

Avoided and Incremental Costs, Net Energy Metering and Distributed Energy Resources

B.3 The Stipulating Parties agree for purposes of this stipulation and without prejudice to the position of any Stipulating Party in any future proceeding that the 2021 component values for the Net Energy Metering ("NEM") Distributed Energy Resources, as shown in Table 5 in the testimony of DEP witness Martin and listed below comply with the NEM methodology approved by the Commission in Order No. 2015-194 and satisfy the requirements of S.C. Code Ann. § 58-40-10, *et seq.*

Components of NEM Distributed Energy Resource Value	Component value ($/kWh) Residential PV[1]	Component value ($ per kWh) for Small PV[1]	Component value ($ per kWh) for Large PV[1]
Marginal Energy Cost	$0.024785	$0.024795	$0.024801
Marginal Capacity Cost	$0.001767	$0.001738	$0.001763
Ancillary Services	($0.002389)	($0.002390)	($0.002390)
T&D Capacity	$0.000000	$0.000000	$0.000000
Avoided Criteria Pollutants[2]	$0.000027	$0.000028	$0.000030
Avoided CO2 Emissions Cost	$0.000000	$0.000000	$0.000000
Fuel Hedge[3]	$0.000000	$0.000000	$0.000000
Utility Integration & Interconnection Cost	$0.000000	$0.000000	$0.000000
Utility Administration Cost	$0.000000	$0.000000	$0.000000
Environmental Costs	$0.000000	$0.000000	$0.000000
Subtotal	**$0.024190**	**$0.024170**	**$0.024204**
Line Losses[4]	$0.000272	$0.000271	$0.000271
Total Value of NEM Distributed Energy	**$0.024461**	**$0.024442**	**$0.024475**

[1] "Residential PV" refers to a load shape reflecting generation installed by a residential customer. "SGS PV" refers to a load shape reflecting generation installed by a small commercial/industrial customer served under Small General Service Schedule SGS. "Large PV" refers to a load shape reflecting generation installed by a customer with higher consumption requirements and applies to all other nonresidential schedules. The Company continues to utilize third-party solar load profile data for non-residential customers.

[2] Avoided Criteria Pollutants reflects NOx and SOx that have been separately identified from approved marginal energy costs.

[3] Pursuant to the Settlement Agreement reached in DEP's 2016 annual fuel proceeding (Docket No. 2016-3-E), the Company has calculated the hedge value and determined that no fuel hedge exists; therefore, the value is zero

[4] Line loss factors are 1.281% for marginal energy and 1.857% for marginal capacity per DEP's updated 2018 line loss analysis based upon 2020 cost of service.

B.4 Upon the issuance of the Commission's final order in the generic docket regarding Net Energy Metering (Docket No. 2019-182-E), DEP shall recalculate the DER incentive and other components which may change as a result of that order. DEP shall file its recalculations with the Commission within 30 days of the issuance of the final order and shall provide its recalculations to the parties in this docket. At that time, parties may propose next steps to account for any differences. Any difference between the DER incentive and other components approved by the Commission in Docket No. 2021-1-E and the recalculated DER incentive and other components reflective of the Commission's Order in Docket No. 2019-182-E will be reflected in the base fuel and DERP Incremental (over)/under collection as of the effective date of the Order in Docket No. 2019-182-E, as applicable, and included in the Company's 2022 fuel filing.

B.5 Distributed Energy Resource Program ("DERP") incremental costs are required by Act 236 to be allocated and recovered based on the same method used by the utility to allocate and recover variable environmental costs and under a separate DERP component of the overall fuel factor. Therefore, ORS analyzed the actual and estimated DERP incremental costs that DEP incurred for the period of March 2020 through February 2021, the estimated costs for the period of March 2021 through June 2021, and the forecasted costs for the period July 2021 through June 2022. The Stipulating Parties agree with the adjustments made by the Company to the DERP incremental costs component. The Parties agree with the ending cumulative balances of DERP incremental costs for February 2021 as an under-recovered $173,595, and June 2021 as an under-recovered $274,531, as calculated by the Company. The Stipulating Parties agree that the appropriate fixed charges per account to recover DERP incremental costs ("DERP Charge") for the period beginning with service rendered from July 1, 2021 through June 30, 2022 are listed below.

DERP Charge[5] ($/account)		
	Annual Charge	Monthly Charge
Residential	12.00	1.00
Commercial	42.39	3.53
Industrial	1,200.00	100.00

B.6 The Stipulating Parties agree that the DERP Charges as set forth above are consistent with S.C. Code Ann. §§ 58-27-865, 58-39-140 and 58-39-150 and with Commission orders.

B.7 The Stipulating Parties agree that, consistent with past practice, under-collected DERP incremental costs resulting from the annual cost caps mandated by Act 236 will earn carrying costs at the three-year treasury rate plus 65 basis points and will be reallocated using each class's contribution to peak demand. The Stipulating Parties agree that in an effort to keep the Stipulating Parties and DEP's customers informed of the (over)/under-recovery balances related to DERP incremental costs, DEP will provide to ORS and, where applicable, its customers, forecasts of the expected DERP Charge to be set at its next annual fuel proceeding based upon DEP's historical (over)/under-recovery to date and DEP's forecast of DERP incremental and avoided costs. Forecasts will be provided in the same manner as forecasts of the expected fuel factor.

B.8 DERP avoided costs are required by Act 236 to be allocated and recovered based on the same method used by the utility to allocate and recover variable environmental costs and under a separate DERP component of the overall fuel factor. Therefore, ORS analyzed the DERP avoided costs that DEP reported and projected for the actual period of March 2020 through February 2021, the estimated costs for the period of March 2021 through June 2021, and the

[5] Gross Receipts Tax included.

forecasted costs for the period July 2021 through June 2022 and found them to be reasonable. The Stipulating Parties agree with the ending cumulative balances of DERP avoided costs for February 2021 as an over-recovered $19,309, and June 2021 as an over-recovered $36,805, as calculated by the Company.

Fuel Expenses and Power Plant Operations

B.9 The Stipulating Parties agree with the adjustments made by the Company to the base fuel component. The Stipulating Parties agree with the ending cumulative balances of base fuel for February 2021 as an under-recovered $10,892,003, and June 2021 as an under-recovered $9,257,175, as calculated by the Company.

B.10 The Stipulating Parties agree with the ending cumulative balances of environmental costs for February 2021 as an over-recovered $348,874, and June 2021 as an over-recovered $483,868, as calculated by the Company.

B.11 ORS also analyzed DEP's calculation of the projected cumulative capacity-related costs. The Stipulating Parties agree with the ending cumulative balances of capacity costs for February 2021 as an under-recovered $5,044,753, and June 2021 as an under-recovered $5,491,437, as calculated by the Company.

B.12 ORS thoroughly reviewed and investigated DEP's nuclear operations during the review period. As shown in ORS witness Bickley's Exhibit BSB-1, DEP's nuclear fleet achieved an average net capacity factor during the review period of 93.13%. DEP achieved this capacity factor notwithstanding the fact that it experienced two (2) scheduled refueling outages, one (1) maintenance outage, and six (6) forced outages during the review period. S.C. Code Ann. § 58-27-865 states that:

> There shall be a rebuttable presumption that an electrical utility made every reasonable effort to minimize cost associated with the operation of its nuclear generation facility or system, as applicable,

> if the utility achieved a net capacity factor of ninety-two and one-half percent or higher during the period under review. The calculation of the net capacity factor shall exclude reasonable outage time associated with reasonable refueling, reasonable maintenance, reasonable repair, and reasonable equipment replacement outages; the reasonable reduced power generation experienced by nuclear units as they approach a refueling outage; the reasonable reduced power generation experienced by nuclear units associated with bringing a unit back to full power after an outage; Nuclear Regulatory Commission required testing outages unless due to the unreasonable acts of the utility; outages found by the commission not to be within the reasonable control of the utility; and acts of God. The calculation also shall exclude reasonable reduced power operations resulting from the demand for electricity being less than the full power output of the utility's nuclear generation system.

Excluding reasonable outage time pursuant to S.C. Code Ann. §58-27-865(F), DEP's net nuclear capacity factor for the review period was 101.56% as reflected in DEP witness Waldrep's Direct Testimony Exhibit 1.

B.13 The Stipulating Parties further agree that, except as noted herein, any challenges to DEP's historical fuel costs recovery for the period ending February 28, 2021, are not subject to further review; however, the projected fuel costs for periods beginning March 1, 2021, and thereafter shall be open issues in future fuel cost proceedings held under the procedure and criteria established in S.C. Code Ann. § 58-27-865.

<u>Fuel Factors</u>

B.14 The appropriate fuel factors for DEP to charge for the period beginning with services rendered in July 2021 and extending through services rendered in June 2022 are listed below. These fuel factors include the South Carolina base fuel costs, environmental costs, avoided capacity and the DERP avoided cost, but do not include gross receipt tax and regulatory fees. The Stipulating Parties agree that the fuel factors will be adjusted for billing purposes to include those amounts.

Class of Service	Base Fuel Component (¢/kWh)	Environmental Component (¢/kWh)	Capacity Related Component (¢/kWh)	DERP Avoided Cost Component (¢/kWh)	Combined Total Fuel Factor (¢/kWh)
Residential[6]	1.887	0.005	0.465	0.003	2.360
General Service (non-demand)	1.874	0.015	0.580	0.004	2.473
General Service (demand)	1.874	[7]	[8]	[9]	1.874
Lighting	1.874	0.000	0.000	0.000	1.874

B.15 The Stipulating Parties agree that the fuel factors set forth above are consistent with S.C. Code Ann. § 58-27-865.

Other

B.16 The Stipulating Parties agree that, except as noted herein, any challenges to DEP's historical fuel costs recovery for the period ending February 28, 2021 are not subject to further review; however, with regard to plant outages not complete as of February 28, 2021, and plant outages where final reports or investigations (Company, contractor, government reports or otherwise) are not available, the Stipulating Parties agree that they retain the right to review the reasonableness of plant outage(s) and associated costs in the review period during which the outage is completed or when the report(s) become available.

B.17 DEP agrees that in an effort to keep the Stipulating Parties and DEP's customers informed of the (over)/under recovery balances related to fuel costs and of DEP's commercially

[6] The Residential Base Fuel Factor includes the Residential Energy Conservation Discount, Rider RECD-2D, adjustment factor of 0.7068%
[7] The Proposed General Service (demand) Environmental Component is 4 cents per kW
[8] The Proposed General Service (demand) Capacity Related Component is 157 cents per kW.
[9] The Proposed General Service (demand) DERP Avoided Cost Component is 1 cent per kW.

reasonable efforts to forecast the expected fuel factor to be set at its next annual fuel proceeding, DEP will provide to the ORS, and where applicable, its other customers, the following information:

a. Copies of the monthly fuel recovery reports currently filed with the Commission and ORS showing the monthly (over)/under-recovery and cumulative balances through the end of the forecast period [10];

b. Copies of the monthly fuel recovery reports currently filed with the Commission, modified to include reports of itemized monthly actual DERP incremental and avoided costs as well as the monthly (over)/under cumulative balances of DERP avoided and incremental costs;

c. Quarterly forecasts (during each of the three (3) quarters in which there is no annual fuel proceeding but not in the quarter where DEP makes its annual fuel filing) of the expected fuel factor to be set at its next annual fuel proceeding based upon DEP's historical (over)/under recovery to date and DEP's forecast of prices for uranium, natural gas, coal, oil and other fuel required for generation of electricity. DEP agrees that it will use commercially reasonable efforts in making these forecasts. To the extent that the forecast data required hereunder is confidential, any party or customer that wants forecasted fuel data will have to sign a non-disclosure agreement to protect the data from public disclosure and to only disclose it to employees or agents with a need to be aware of this information.

d. Forecasts of the expected DERP Charge to be set at its next annual fuel proceeding based upon DEP's historical (over)/under-recovery to date and

[10] The Company agrees to break-out Schedule 4 of the monthly fuel recovery reports so that each component (base fuel, environmental, avoided capacity, and DER avoided costs) is reported separately.

DEP's forecast of DERP incremental and avoided costs. Forecasts will be provided in the same manner as B.16(c) above.

B.18 The Stipulating Parties agree that DEP's methodology for determining the environmental cost component of the fuel factor and the methodology for allocation and recovery of the capacity-related cost component of the fuel factor (which includes purchased power capacity costs under the Public Utility Regulatory Policies Act of 1978 and natural gas transportation and storage costs) are consistent with the statutory requirements of S.C. Code Ann. § 58-27-865.

B.19 In Act 236, the Legislature included a specific requirement that all capacity costs that are recovered through the fuel factor must be allocated and recovered in accordance with the method used by the utility to recover variable environmental costs and included in a separate component of the fuel factor. *See* S.C. Code Section 58-27-865(A)(1). ORS has reviewed DEP's methodology for determining the environmental cost component of the fuel factor and the methodology for allocation and recovery of the capacity-related cost component of the fuel factor (which includes purchased power capacity costs under the Public Utility Regulatory Policies Act of 1978 ("PURPA") and natural gas transportation and storage costs), and the Parties agree that the methodology used by DEP in this proceeding are consistent with the statutory requirements of S.C. Code Ann. § 58-27-865.

B.20 DEP agrees to continue to examine and make adjustments, as necessary, to its natural gas hedging program in light of the potentially reduced volatility in the domestic natural gas market. DEP also agrees to provide monthly natural gas hedging reports to the ORS.

B.21 Nothing contained in this Stipulation alters, amends, or changes the methodology established for determining the environmental factor for DEP's rate classes as set forth in Paragraphs 3(B) and (C) of the Stipulation filed with and approved by the Commission in Docket No. 2007-1-E.

C. REMAINING STIPULATION TERMS AND CONDITIONS

C.1 Further, ORS is charged by law with the duty to represent the public interest of South Carolina pursuant to S.C. Code Ann. § 58-4-10(B). S.C. Code Ann. § 58-4-10(B) reads in part as follows:

> . . . 'public interest' means the concerns of the using and consuming public with respect to public utility services, regardless of the class of customer and preservation of continued investment in and maintenance of utility facilities so as to provide reliable and high quality utility services.

ORS believes this Stipulation serves the public interest as defined above.

C.2 The Stipulating Parties agree that this Stipulation is reasonable, is in the public interest, and is in accordance with law and regulatory policy. This Stipulation in no way constitutes a waiver or acceptance of the position of any Stipulating Party concerning the requirements of S.C. Code Ann. § 58-27-865, S.C. Code Ann. § 58-39-10, *et seq*, S.C. Code Ann. § 58-40-10, *et seq*, and Commission Order 2015-194 in any future proceeding.

C.3 The Stipulating Parties agree to cooperate in good faith with one another in recommending to the Commission that this Stipulation be accepted and approved by the Commission as a fair, reasonable and full resolution in the above-captioned proceeding.

C.4 This written Stipulation contains the complete agreement of the Stipulating Parties regarding this matter. There are no other terms or conditions to which the Stipulating Parties have agreed. This Stipulation integrates all discussions among the Stipulating Parties into the terms of this written document. The Stipulating Parties agree that this Stipulation will not constrain, inhibit or impair their arguments or positions held in future proceedings, nor will this Stipulation or any of the matters agreed to in it be used as evidence or precedent in any future proceeding. If the Commission should decline to approve this Stipulation in its entirety, then any Stipulating Party desiring to do so may withdraw from this Stipulation without penalty.

C.5 This Stipulation shall be interpreted according to South Carolina law.

C.6 Except as expressly set forth herein, this Stipulation in no way constitutes a waiver or acceptance of the position of any Stipulating Party concerning the requirements of S.C. Code Ann. § 58-27-865, S.C. Code Ann. § 58-39-10, *et seq*, S.C. Code Ann. § 58-40-10, *et seq*, and Commission Order No. 2015-194 in any future proceeding. This Stipulation does not establish any precedent with respect to the issues resolved herein, and in no way precludes any Party herein from advocating an alternative methodology under S.C. Code Ann. § 58-27-865, S.C. Code Ann. § 58-39-10, *et seq*, S.C. Code Ann. § 58-40-10, *et seq*, and Commission Order No. 2015-194 in any future proceeding.

C.7 This Stipulation shall bind and inure to the benefit of each of the signatories hereto and their representatives, predecessors, successors, assigns, agents, shareholders, officers, directors (in their individual and representative capacities), subsidiaries, affiliates, parent corporations, if any, joint ventures, heirs, executors, administrators, trustees, and attorneys.

C.8 The Stipulating Parties represent that the terms of this Stipulation are based upon full and accurate information known as of the date this Stipulation is executed. If, after execution, but prior to a Commission decision on the merits of this proceeding, a Stipulating Party is made aware of information that conflicts, nullifies, or is otherwise materially different than that information upon which this Stipulation is based, that Stipulating Party may withdraw from the Stipulation with written notice to every other Stipulating Party

C.9 The above terms and conditions fully represent the agreement of the Stipulating Parties. Therefore, each Stipulating Party acknowledges its consent and agreement to this Stipulation by authorizing its counsel to affix his or her signature to this document where indicated below. Counsel's signature represents his or her representation that his or her client has authorized the execution of the agreement. Facsimile signatures and e-mail signatures shall be as effective as original signatures to bind any Stipulating Party. This document may be signed in counterparts, with the various signature pages combined with the body of the document constituting an original and provable copy of this Stipulation.

[PARTY SIGNATURES TO FOLLOW ON SEPARATE PAGES]

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RENEWABLE NET METERING RIDER RNM-~~10~~11

AVAILABILITY

This Rider is closed to new participants on and after June 1, 2021. Customers requesting net energy metered (NEM) service on and after June 1, 2021 will receive service in accordance with the NEM tariff(s) in effect at that time.

Participants and subsequent owners of the customer-generator facility (collectively, "Participants") who applied for service under this Rider prior to May 16, 2019 shall remain eligible for standard service under this Rider until December 31, 2025. Participants who applied for service under this Rider on and after May 16, 2019 and prior to June 1, 2021 shall remain eligible for standard service under this Rider until May 31, 2029. Participants will be given the option to transfer to Schedule R-STOU (Residential Service, Solar Time-of-Use) and Rider RSC (Residential Solar Choice) beginning January 1, 2022. If Participants elect not to transfer to Schedule R-STOU and Rider RSC by the applicable sunset date of December 31, 2025 or May 31, 2029, they may continue to receive service under this Rider and their applicable rate schedule subject to the following provisions:

1. Any volumetric price increase after their applicable sunset date will be placed in a non-bypassable charge based on the estimated total solar energy production of their system size.
2. Participants will be assessed a monthly minimum bill set at $10 more than the Basic Facilities Charge at that time.

Monthly Excess Energy will be credited at the avoided cost rate in effect at that time, rather than carry forward to the next billing month.

Available to residential and nonresidential Customers receiving concurrent service from Company, on a metered rate schedule, except as indicated under General Provisions. A customer-generator is a owner, operator, or lessee of an electric generation unit that generates or discharges electricity from a renewable energy resource, including an energy storage device configured to receive electrical charge solely from an onsite renewable energy resource. The renewable NEM generation, which includes a solar photovoltaic; solar thermal; wind powered; hydroelectric; geothermal; tidal or wave energy; recycling resource; hydrogen fueled or combined heat and power derived from renewable resources; or biomass fueled generation source of energy, is installed on Customer's side of the delivery point, for Customer's own use, interconnected with and operated in parallel with Company's system. The generation must be located at a single premise owned, operated, leased or otherwise controlled by Customer.

GENERAL PROVISIONS

1. To qualify for service under this Rider, Customer must comply with all applicable interconnection standards and must provide, in writing, the Nameplate Capacity of Customer's installed renewable generation system. Any subsequent change to the Nameplate Capacity must be provided by Customer to Company in writing by no later than 60 days following the change.

2. To qualify for service under this Rider, a residential customer may be served on an approved residential rate schedule, but may not be served under Rider NM. The Nameplate Capacity of Customer's installed generation system and equipment must not exceed 20 kW AC.

3. To qualify for service under this Rider, a nonresidential customer may be served on an approved general service rate schedule, but may not be served on Schedules SGS-TES, TSS, TFS, LGS-RTP, LGS-CUR-TOU, CSG, CSE, GS, SFLS, SGS-TOU-CLR or Rider NM. The Nameplate Capacity of Customer's installed renewable generation system and equipment must not exceed 1,000 kW AC or

100% of Customer's contract demand which shall approximate Customer's maximum expected demand.

4. If Customer is not the owner of the premises receiving electric service from Company, Company shall have the right to require that the owner of the premises give satisfactory written approval of Customer's request for service under this Rider.

5. All environmental attributes, including but not limited to "renewable energy certificates" (RECs), "renewable energy credits" or "green tags", associated with the generation system shall be conveyed to Company until billing of a Distributed Energy Resource Program Rider DERP Charge is discontinued on all customer bills. Customer certifies that the environmental attributes have not and will not be remarketed or otherwise resold for any purpose, including another distributed energy resource standard or voluntary purchase of renewable energy certificates in South Carolina or in any other state or country for the Contract Period and any successive contract periods thereto.

6. If the electricity supplied to Customer by Company exceeds the electricity delivered to the grid by the customer-generator during a monthly billing period, the customer-generator shall be billed for the net electricity in kilowatt hours (kWh) supplied by Company plus any demand or other charges under the applicable rate schedule or riders.

7. Electricity delivered to the grid by Customer's renewable generation that exceeds the electricity delivered by Company during a monthly billing period is defined as Excess Energy. When used in conjunction with a time of use schedule, the TOU periods shall be specified in the applicable schedule and any Excess Energy shall apply first with the Excess Energy generated On-Peak kWh offsetting On-peak usage and then offsetting Off-peak usage. Any excess Off-Peak kWh shall only apply against Off-peak kWh usage. Any Excess Energy not used in the current month to offset usage shall carry forward to the next billing month, except for Participants served under this Rider beyond the applicable sunset date of December 31, 2025 or May 31, 2029, for which Excess Energy will be credited at the end of each billing month.

8. Excess Energy shall be used to reduce electricity delivered and billed by Company during the current or a future month, except that for the March billing period any carry-over shall be compensated as described in the RATE paragraph below. In the event Company determines that it is necessary to increase the capacity of facilities beyond those required to serve Customer's electrical requirement or to install a dedicated transformer or other equipment to protect the safety and adequacy of electric service provided to other customers, Customer shall pay the estimated cost of the required transformer or other equipment above the estimated cost which Company would otherwise have normally incurred to serve Customer's electrical requirement, in advance of receiving service under this Rider.

9. The rates set forth herein are subject to Commission Order No. 2015-194, issued in Docket No. 2014-246-E pursuant to the terms of S.C. Code § 58-40-20(F)(4). Eligibility for this rate will terminate as set forth in that Order, and otherwise as specified above. The value of NEM generation eligible for this Rider shall be computed using the methodology contained in Commission Order No. 2015-194, in Docket No. 2014-246-E, and shall be updated annually by Company. The value of NEM generation for ~~2020~~ 2021 is $~~0.02445~~0.02446 per kWh for Schedules RES and R-TOUD, $~~0.02443~~0.02444 for Schedule SGS and $~~0.02446~~0.02448 for all other schedules.

RATE

All provisions of the applicable schedule and other applicable riders will apply to service supplied under this Rider, except as modified herein. For any bill month during which the Energy Charges are a net credit, the respective Energy Charges for the month shall be zero. Credits shall not offset the Basic

Facilities Charge or the Demand Charge (if applicable). In addition to all charges in the applicable rate schedule for Customer's net electrical usage, the following credit may be applicable annually:

Credit for Excess Energy

If Customer has Excess Energy after offsetting usage as of the date of the March billing, Company shall pay Customer for the amount of the accumulated Excess Energy times a rate of $0.03360 per kWh, after which the amount of Excess Energy shall be set to zero.

Participants served under this Rider beyond the applicable sunset date of December 31, 2025 or May 31, 2029 will receive credit for Excess Energy for each billing month. These Participants will also be assessed a monthly non-bypassable charge based on their Nameplate Capacity for any volumetric price increase thereafter.

MINIMUM BILL

The monthly minimum bill for customers receiving service under this Rider shall be no less than Basic Facilities Charge from the applicable rate schedule and riders plus, if applicable, any of the following Charges: the Demand Charge, the Off-peak Excess Demand Charge, and the Extra Facilities Charge.

Participants served under this Rider beyond the applicable sunset date of December 31, 2025 or May 31, 2029 will be assessed a monthly minimum bill set at $10 more than the Basic Facilities Charge at that time. The minimum bill will be satisfied by the Basic Facilities Charge, the portion of the Customer's monthly volumetric energy charges specific to customer and distribution costs, and riders.

Bill credits for net excess energy are not included in the calculation of the minimum bill charge. Bill credits will reduce a Customer's total bill after the minimum bill charge has been applied.

METERING REQUIREMENTS

Company will furnish, install, own and maintain a billing meter to measure the kilowatt demand delivered by Company to Customer, and to measure the net kWh purchased by Customer or delivered to Company. For renewable generation capacity of 20 kW AC or less, the billing meter will be a single, bi-directional meter which records independently the net flow of electricity in each direction through the meter, unless Customer's overall electrical requirement merits a different meter. For larger renewable generation capacities, Company may elect to require two meters with 15-minute interval capabilities to separately record Customer's electrical consumption and the total generator output, which will be electronically netted for billing. Customer grants Company the right to install, operate, and monitor special equipment to measure Customer's generating system output, or any part thereof, and to obtain any other data necessary to determine the operating characteristics and effects of the installation. All metering shall be at a location that is readily accessible by Company.

SAFETY, INTERCONNECTION AND INSPECTION REQUIREMENTS

This Rider is only applicable for installed renewable generation systems and equipment that complies with and meets all safety, performance, interconnection, and reliability standards established by the Commission, the National Electric Code, the National Electrical Safety Code, the Institute of Electrical and Electronic Engineers, Underwriter's Laboratories, the Federal Energy Regulatory Commission and any local governing authorities. Customer must comply with all liability insurance requirements of the Interconnection Standard.

POWER FACTOR

Customer's renewable generation must be operated to maintain a 100% power factor, unless otherwise specified by Company. When the average monthly power factor of the power supplied by Customer to Company is other than 100%, the Low Power Factor Adjustment stated in Company's Service Regulations may be applicable. Company reserves the right to install facilities necessary for the measurement of power factor. Company will not install such equipment, nor charge a Low Power Factor Adjustment if the renewable generation system is less than 20 kW AC and uses an inverter.

CONTRACT PERIOD

Customer shall enter into a contract for service under this Rider for a minimum original term of one (1) year, and shall automatically renew thereafter, except that either party may terminate the contract after one year by giving at least sixty (60) days prior notice of such termination in writing.

Company reserves the right to terminate Customer's contract under this Rider at any time upon written notice to Customer in the event that Customer violates any of the terms or conditions of this Rider, or operates the renewable generation system and equipment in a manner which is detrimental to Company or any of its customers. In the event of early termination of a contract under this Rider, Customer will be required to pay Company for the costs due to such early termination, in accordance with Company's South Carolina Service Regulations.